TECHNICAL REVIEW AND EVALUATION OF APPLICATION FOR AIR QUALITY PERMIT NO. 1000107

I. INTRODUCTION

This Title V permit is for the operation of the Yucca Power Plant, located just to the northwest of Yuma, which is jointly owned by Arizona Public Service Company (APS) and Imperial Irrigation District (IID). The Yucca plant provides power to the electric grid on an as-needed-basis, primarily during summer months when air conditioning power demands are high.

A. Company Information

Facility Name: Yucca Power Plant
Mailing Address: 7522 S. Somerton Avenue, Yuma, Yuma County, AZ 85364
Facility Address: 7522 S. Somerton Avenue, Yuma, Yuma County, AZ 85364

B. Attainment Classification

The source is in an attainment area for TSP, SO_2, CO, Ozone, and NO_2. The source is in a nonattainment area for PM-10.

II. PROCESS DESCRIPTION

The maximum process rates and operating hours of the significant points of emissions at Yucca are summarized in Table 1. Operational flexibility provides the ability to operate the single Steam Unit, and the five Combustion Turbines in any combination as required. The plant also has the flexibility to operate the Auxiliary Boiler to provide heat for fuel oil and maintenance activities.

Table 1: Maximum Process Rates

Unit	Hours/yr	MW	MW-hr/yr
Steam Unit #1	8760	80	700800
Turbine #1	8760	22	192720
Turbine #2	8760	22	192720
Turbine #3	8760	67	586920
Turbine #4	8760	66	578160
Turbine #21	8760	23.2	203232
Total			2454552

The Yucca Power Plant currently has the capability to burn natural gas and/or fuel oil. The Steam Unit, all five combustion turbines, and the Auxiliary Boiler can be operated at a capacity factor of 0 to 100%. Table 2 summarizes the normal and the alternate operating scenarios at the Yucca plant. Data from the emission sources forms shows that Yucca potentially emits more than 100 tons per year (tpy) of all primary criteria pollutants (except lead) and more than 10 tpy of formaldehyde and nickel.

Table 2: Operating Scenarios

Source	Normal Operating Scenarios	Alternate Operating Scenarios
Steam Unit	Natural Gas	
		#4 through #6 grades Fuel Oil
		Co-firing #4 through #6 grades Fuel Oil and Natural Gas
Combustion Turbines #1,2, and 3	Natural Gas	
		#2 Fuel Oil
		Co-firing #2 Fuel Oil and Natural Gas
Combustion Turbines #4 and 21	#2 Fuel Oil	Natural Gas
		Co-firing #2 Fuel Oil and Natural Gas
Auxiliary Boiler	Natural Gas	
		#4 through #6 grades Fuel Oil
		Co-firing #4 through #6 grades Fuel Oil and Natural Gas

III. EMISSIONS

The Yucca plant has the capability of operating under different scenarios as outlined in Section II of this Technical Remarks document. Typical operating parameters of the turbines, the steam unit and the auxiliary boiler are given in Table 3. Table 4 summarizes the potential to emit (PTE), allowable emissions, test results, and the emissions inventory (EI) for these units. The emission factors used to calculate the potential to emit are from AP-42 (1/95 ed.). APS, in its application, provided the emission factors for the gas turbines and the steam generator from EPA publication EPA 450/4-90-003. These numbers do not vary significantly from AP-42 numbers. The allowable emissions are calculated using the standards under A.A.C. R18-2-703 and A.A.C. R18-2-719. Although calculations have been shown here only for the worst-case scenario of burning fuel oil no. 6 in the steam unit and the auxiliary boiler, the steam unit and the auxiliary boiler have the capability to burn fuel oil nos. 4 through 6. The reader is advised to peruse the permit application for HAPs emissions calculations. For other emissions calculations, the reader is referred to the attachment to this technical support document.

Table 3: Typical Operating Parameters

Description	Steam Unit	Gas Turbines		Auxiliary Boiler
		Units 1, 2, 21 (Frame 5)	Units 3 and 4 (Frame 7)	
Average generating capacity (KW)	80,419	19,000	58,000	N/A
Maximum generating capacity (KW)	80,419	22,000	67,000	N/A
Net heat rate at average capacity (Btu/KWh)	10,425	14,482	13,886	N/A
Net heat rate at maximum capacity (Btu/KWh)	10,425	13,966	13,653	N/A
Heating value of natural gas (Btu/scf)	1027	1027	1027	1027
Heating value of fuel oil (Btu/gal)	148,871	138,920	138,920	148,871
Specific gravity, API (oil)	17.6	33.2	33.2	17.6
Density of oil (lb/gal)	7.92	7.17	7.17	7.92

While AP-42 emissions factors from 1/95 are more recent and more accurate than the emission factors used by APS, the resulting increases (and decreases in some cases) in calculated emissions do not change the source category status, and do not trigger any new applicable requirements. Therefore, the use of emission factors from EPA 450/4-90-003 to calculate emissions is acceptable.

The formula used to calculate the uncontrolled emissions from units burning natural gas is as follows:

Emissions (tpy) = Emission Factor (lb/MMscf) x Net Heat Rate (Btu/KWh) x Max. Generating Capacity (KW)/Heating Value of Fuel (Btu/scf)/10^6 (scf/MMscf) x 8760 (hr/yr)/2000 (lbs/ton)

The formula used to calculate the uncontrolled emissions from units burning fuel oil is as follows:

Emissions (tpy) = Emission Factor (lb/1000 gal) x Net Heat Rate (Btu/KWh) x Max. Generating Capacity (KW)/Heating Value of Fuel (Btu/gal) x 8760 (hr/yr)/2000 (lbs/ton)

Potential emissions from the Yucca plant are presented in the following table. They may be used for the following purposes:

(i) Ascertaining "major source" status of the Yucca plant pursuant to CAA Sec 501 (2);
(ii) Comparing source potential-to-emit with emission rates allowable by relevant standards; and
(iii) Comparing source potential-to-emit with emissions inventory and test data.

This comparison serves as a summary of existing information on emissions from the Yucca plant. These emissions calculations are **not** meant to establish any baseline emissions levels. These emissions figures (except for the ALLOWABLE emissions) are **not** meant to be emissions limitations of any form.

Table 4: Comparison among PTE, Allowable Emissions, Test Data, and EI

Unit	Pollutant	PTE (tpy)	Allowable (tpy)	Test Data (tpy)	EI 1996 (tpy)
Steam Unit 1 (Natural gas)	PM	10.73	791.03**	n/a	3.71
	SOx	2.15	n/a	n/a	0.74
	NOx	1200(1)	n/a	1200(1)	340.45
	VOCs	5.01	n/a	n/a	1.73
	CO	143.02	n/a	n/a	49.52
Turbines #1 and #2 (Natural gas)	PM	56.35**	365.56**	n/a	0.14*
	SOx	0.86**	n/a	n/a	0.00*
	NOx	592.29**	n/a	n/a	4.12*
	VOCs	32.24**	n/a	n/a	0.12*
	CO	148.07**	n/a	n/a	1.15*
Turbine #3 (Natural gas)	PM	167.75	845.89**	n/a	0.75
	SOx	2.57	n/a	n/a	0.03
	NOx	1763.38	n/a	n/a	22.18
	VOCs	95.97	n/a	n/a	0.68

Unit	Pollutant	PTE (tpy)	Allowable (tpy)	Test Data (tpy)	EI 1996 (tpy)
	CO	440.84	n/a	n/a	6.18
Auxiliary Boiler (Natural gas)	PM	0.91	119.77**	n/a	n/a
	SOx	0.18	n/a	n/a	n/a
	NOX	83.51	n/a	n/a	n/a
	VOCs	0.43	n/a	n/a	n/a
	CO	12.15	n/a	n/a	n/a
Steam Unit 1 (Fuel oil #6)	PM	236.79	791.03**	n/a	2.09
	SOx	2671.33	3672.05**	n/a	23.88
	NOx	1035.97	n/a	n/a	20.32
	VOCs	18.75	n/a	n/a	0.21
	CO	123.33	n/a	n/a	1.41
Turbines #1, #2 and #21 (Fuel oil #2)	PM	82.34**	365.56**	n/a	0.01*
	SOx	394.27**	1345.76**	n/a	0.10*
	NOx	939.67**	n/a	n/a	0.17*
	VOCs	23.25**	n/a	n/a	0.01*
	CO	64.91**	n/a	n/a	0.04*
Turbines #3 and #4 (Fuel oil #2)	PM	245.15**	845.89**	n/a	0.20*
	SOx	1173.83**	4006.61**	n/a	1.67*
	NOx	2797.59**	n/a	n/a	2.79*
	VOCs	69.22**	n/a	n/a	0.00*
	CO	193.24**	n/a	n/a	0.63*
Auxiliary Boiler (Fuel oil #6)	PM	20.11	119.77**	n/a	n/a
	SOx	226.87	315.36**	n/a	n/a
	NOx	87.98	n/a	n/a	n/a
	VOCs	1.59	n/a	n/a	n/a

Unit	Pollutant	PTE (tpy)	Allowable (tpy)	Test Data (tpy)	EI 1996 (tpy)
	CO	10.47	n/a	n/a	n/a

Notes: * The numbers shown are the totals for all the units listed in column 1;

** The numbers shown are the emissions from each unit in column 1;

(1) Test result (1200 tpy) indicated emissions greater than the PTE (983 tpy) and hence PTE has been replaced with the test result.

n/a Not available

IV. COMPLIANCE HISTORY

A. Inspections

Inspections are being regularly conducted on this source to ensure compliance with the permit conditions. Table 5 summarizes some of the recent inspections that have been conducted on the source and the results of the inspections.

Table 5: Inspection Results

Inspection Date	Type of Inspection	Results
August 7, 1996	Level 2 (FAR No. 15922)	Opacity of the steam generator was less than 5%. Only heat waves were observed to be emanating from the stack. The inspection indicated that the source was in compliance.
January 1, 1996	Level 2 (FAR No. 14628)	Opacity of the steam generator was less than 5%. Only heat waves were observed to be emanating from the stack. Only steam generator was operating at 22 MW. The inspection indicated that the source was in compliance.
March 30, 1994	Level 2 (FAR No. 10727)	Opacity of the steam generator was less than 5%. Only the steam generator was operating at 20 MW. The inspection indicated that the source was in compliance.
July 8, 1992	Level 2 (FAR no. 9595)	Only the steam generator was operating at 21 MW. The inspection indicated that the source was in compliance.

November 27, 1991	Level 2 (FAR No. 8876)	Only the steam generator was operating at 38 MW. The inspection indicated that the source was in compliance.

B. Excess Emissions

There have been no cases of excess emissions from the Yucca power plant.

C. Testing

APS conducted a performance test in June 1995 on steam unit 1 for NOx emissions. The average emissions of NOx from this unit was 230.9 ppm or 0.327 lb/MMBtu. Results of this compliance test are shown in Table 6.

Table 6: Test Results

Date of Test	Equipment Tested	Pollutants Tested	Results
6/21/95	Steam Unit 1	NOx (Method 7E)	Passed

D. Compliance Certifications

After the issuance of this Part 70 permit, the Permittee will be required to submit compliance certifications every six months as indicated in Section VII of Attachment "A" of the permit. APS has clearly specified in Sections A1-16 and A1-17 of the permit application that it operates all emission units in compliance with applicable requirements and will continue to comply with all applicable requirements under the existing operating permits. In addition, APS will comply with all applicable requirements that become effective during the permit term on a timely basis.

APS has clearly specified in Section A1-17 of the permit application that it will submit an annual compliance certification report which will identify the status of compliance in terms of continuous or intermittent compliance. The compliance certification will be signed by the responsible official ascertaining the truth, accuracy, and completeness of the information provided. The certification will include information pertaining to the methods used for determining the compliance status of the sources of emissions from APS operations. The information will be based on monitoring results compiled over the reporting period as prescribed in the permit. However, the Title V permit stipulates that the source is required to submit semi-annual compliance certifications.

V. APPLICABLE REGULATIONS VERIFICATION

The Permittee has identified the applicable regulations that apply to each unit in its permit application. Table 7 summarizes the findings of the Department with respect to the regulations that apply to each unit. Installation Permit and other previous permit conditions are discussed under the Section VI of this technical review document.

Table 7: Applicable Regulations Verification

Unit ID	Start-up date	Control Equipment	Applicable Regulations	Verification
Steam Unit 1	3/4/59	None	A.A.C. R18-2-702.B A.A.C. R18-2-703.A A.A.C. R18-2-703.B A.A.C. R18-2-703.C.1 A.A.C. R18-2-703.E.1 A.A.C. R18-2-703.H A.A.C. R18-2-703.J A.A.C. R18-2-703.K 40 CFR 73 40 CFR 75	The start-up date of this unit predates the enactment of the Act. Since the heat input is 838 MMBtu/hr (>250 MMBtu/hr), this unit is subject to R18-2-703. NOx standards are not applicable to this source because the start-up date is prior to May 30, 1972. For the same reason, the SOx standard of 1.0 lb/MMBtu applies.
Gas Turbine 1	7/1/71	None	A.A.C. R18-2-719.A A.A.C. R18-2-719.B A.A.C. R18-2-719.C.1 A.A.C. R18-2-719.E A.A.C. R18-2-719.F A.A.C. R18-2-719.H A.A.C. R18-2-719.I A.A.C. R18-2-719.J A.A.C. R18-2-719.K	The start-up date of this unit is prior to October 3, 1977, and hence is not subject to 40 CFR 60, Subpart GG. This unit is subject to the opacity standard of 40% and the sulfur dioxide standard of 1.0 lb/MMBtu.
Gas Turbine 2	7/1/71	None	Same as above	Same as above
Gas Turbine 3	6/20/73	None	Same as above	Same as above
Gas Turbine 4	7/9/74	None	Same as above	Same as above
Gas Turbine 21	12/28/78	None	Same as above	Although the start-up date is later than the trigger date of Subpart GG, the equipment was installed prior to 1977. Hence, this unit is subject to R18-2-719. This unit is subject to an opacity standard of 40% and a sulfur dioxide standard of 1.0 lb/MMBtu.
Auxiliary Boiler	1974	None	A.A.C. R18-2-724.A A.A.C. R18-2-724.B A.A.C. R18-2-724.C.1 A.A.C. R18-2-724.E A.A.C. R18-2-724.G A.A.C. R18-2-724.J A.A.C. R18-2-724.K	The heat input of this unit is 71 MMBtu/hr (< 250 MMBtu/hr) and the date of construction is prior to the trigger date (6/9/89) for 40 CFR 60, Subpart Dc. Hence, this unit is subject to R18-2-724. The unit is subject to an opacity standard of 15% and a Sulfur dioxide standard of 1.0 lb/MMBtu.

VI. PREVIOUS PERMITS AND CONDITIONS

A. Previous Permits

Date Permit Issued	Permit No.	Application Basis
July 21, 1992	0379-95	Renewal of Permit No. 94006-89

The Permittee has been operating the source in compliance with conditions under this permit as could be seen from the inspection reports in Section IV.A of this technical review document.

B. Previous Permit Conditions

Operating Permit No. 0379-95

Some of the relevant conditions of this permit are as follows:

1. Operate equipment in compliance with all the applicable conditions of A.A.C. R18-2-503, A.A.C. R18-2-519, and A.A.C. R18-2-524.

2. Emission limit on particulate matter emissions from the steam unit, auxiliary boiler, and gas turbines based on heat input.

3. Emission limit on sulfur dioxide emissions of 1.0 lb/MMBtu from the steam unit, auxiliary boiler, and gas turbines.

4. Opacity limit of 40% on gaseous emissions from steam unit, auxiliary boiler, and gas turbines.

5. Performance test equipment including boilers and turbines when that piece of equipment is operated for more than 720 hours/year.

6. Permittee can use only natural gas or fuel oil no.6 in the steam unit and the auxiliary boiler, distillate oil or fuel oil in turbine 4, distillate oil no. 2 in turbine 21, and natural gas or distillate oil no. 2 in turbines 1, 2, and 3.

7. Sulfur content and lower heating value of fuel oil burned in the boilers and turbines to be determined twice per year and any time a shipment of oil is added to the fuel oil storage tank.

8. Average sulfur content, heat content, and quantity of fuel oil burned and heat content

and quantity of natural gas burned shall be record daily.

All the conditions from this permit have been carried over in essence to the Title V permit and have been streamlined with the current SIP. The permit condition to test an equipment that has operated for more than 720 hours has been revised so that an equipment is tested based on its ability to be a major point of emission. For the Frame 5 turbines this has been revised to 930 hours of operation per year and for the Frame 7 turbines this has been revised to 310 hours per year of operation.

VII. PERIODIC MONITORING

A. Steam Unit

Opacity: The steam unit is subject to the opacity standard of < 40% under the general visible emissions rule in A.A.C. R18-2-702.B. This unit burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6.

Natural gas: Natural gas is a clean burning fuel and inspections (see Table 5 under Section IV.A of this technical remarks section) indicate that there have been no opacity problems with this unit. Hence, no monitoring is required when burning natural gas.

Fuel oil: Since this unit meets the definition of a natural gas-fired unit under Part 72, it is not required to have a continuous opacity monitor. However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

1. When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

2. When fuel oil is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

The permittee is also required to monitor and record the number of hours fuel oil is burned continuously in the unit. The time period of 48 hours was established through meetings with the stakeholders. This time period is of particular importance to the stations where there may not be a certified opacity observer to conduct observations during weekends, holidays, etc.

PM: The unit is also subject to the particulate matter emissions standard in A.A.C. R18-2-703.C.1. This unit burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6.

Natural gas: Natural gas is a clean burning fuel and results in negligible particulate matter emissions as demonstrated by engineering calculations and tabulated under the PTE column in Table 4. Therefore, it was determined that a verification though engineering calculation would fulfill the requirements for periodic monitoring when burning natural gas.

Fuel oil: However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit. The permittee is also required to monitor the following information about the fuel found in the purchase specification:

1. Heating value; and
2. Ash content;

Ash content is not an accurate measure but is a good indicator of particulate matter emissions, and monitoring this would help the agency to "ballpark" the particulate matter emissions. No engineering estimation using ash content is prescribed in the permit since it could be interpreted to incorrectly correlate particulate matter emissions to ash content only. Permittee is required to keep on record a copy of the contractual agreement. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

SOx: The steam unit is subject to the sulfur dioxide standard in A.A.C. R18-2-703.E.1 since the unit was placed in commercial operation in 1959. This standard applies only when the unit burns fuel oil. There is no standard when the unit burns natural gas.

Fuel oil: When fuel oil is burned, the Permittee is required to keep on record the purchase specification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and

3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SOx emissions using the information from above according to the following equation for any change in (2) above:

SO2 (lb/MMBtu) = 2.0 x [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Alternatively, the permittee could use the sulfur dioxide emissions recorded by the data acquisition and handling system for monitoring purposes. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

NOx: The steam unit was placed in commercial operation on 3/4/1959. The nitrogen oxides standard under A.A.C. R18-2-703.I does not apply to this unit. Hence no monitoring is being required. Although there is no applicable standard for nitrogen oxides, this source is subject to Title IV requirements and is required to operate, maintain, and calibrate a CEMS for NOx under Title IV. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

B. Gas Turbine Nos. 1, 2, 3, 4, and 21 and Combustion Turbine Diesel Starting Engine Nos. 1, 2, and 21

APS through its letter dated August 31 ,1998, requested that it be allowed to burn natural gas in Gas Turbine Nos. 4 and 21 as part of this renewal. Currently, these turbines burn fuel oil no. 2 only. As a result of this change, emissions are expected to decrease except for that of carbon monoxide. However, the increase in carbon monoxide is far less compared to the significance level. The proposed addition of natural gas as an alternate fuel does not trigger “modification”. Under 40 CFR 60.14, modification is any physical or operational change to an existing facility that results in an increase in the emission rate of any pollutant to which a standard applies. Burning natural gas does not result in the increase in the emissions to the atmosphere of any pollutant to which a standard applies.

Nor does the addition of natural gas constitute “reconstruction” under 40 CFR 60.15. To constitute a “reconstruction”, the fixed capital cost of the new components must exceed 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Typical cost estimates for new combustion turbine is $325 per kilowatt.

Therefore, an expenditure of $14.3 million would be required to trigger 60.15. The cost to install the natural gas controls is approximately $1.4 million.

Opacity: The turbines are subject to the opacity standard of < 40% in A.A.C. R18-2-719.E. Gas turbine Nos. 1, 2, and 3 burn natural gas primarily and are capable of burning fuel oil no. 2. Gas turbine Nos. 4 and 21 burn fuel oil no. 2 primarily and are being fitted with natural gas burners as part of this renewal.

Natural gas: Natural gas is a clean burning fuel and usually does not pose a visible emissions problem. Hence, no monitoring is required when burning natural gas.

Fuel oil: However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

1. When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

2. When fuel oil is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

PM: The units are also subject to the particulate matter emissions standard in A.A.C. R18-2-719.C.1.

Natural gas: Natural gas is a clean burning fuel and results in negligible particulate matter emissions as demonstrated by engineering calculations and tabulated under the PTE column in Table 4. Therefore, it was determined that a verification though engineering calculation would fulfill the requirements for periodic monitoring when burning natural gas.

Fuel oil: However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit. The permittee is also required to monitor the following information about the fuel found in the purchase specification:

1. Heating value; and
2. Ash content;

Ash content is not an accurate measure but is a good indicator of particulate matter emissions, and monitoring this would help the agency to "ballpark" the particulate matter emissions. No engineering estimation using ash content is prescribed in the permit since it could be interpreted to incorrectly correlate particulate matter emissions to ash content only. Permittee is required to keep on record a copy of the contractual agreement. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit. It can be seen that the PTE is only 22% of the allowable emissions in case of gas turbine nos. 1, 2, and 21 and only 29% in case of the gas turbine nos. 3 and 4.

SOx: The turbines are subject to the sulfur dioxide standard in A.A.C. R18-2-719.F. This standard applies only when the unit burns fuel oil.

Natural gas: "Pipeline-quality" natural gas has to conform to standards approved by the Federal Energy Regulatory Commission (FERC). One of the FERC standards limits the sulfur content in the gas to less than 5 grains/100 scf (which is equivalent to 0.017 weight percent of sulfur). Another standard specifies that the heating value must be greater than or equal to 967 Btu per cubic foot. APS runs the gas turbines with fuel drawn from their pipeline, and therefore maintaining a copy of the FERC approved Tariff agreement on-site is an adequate means of complying with the monitoring requirements for the particulate, opacity and fuel use standards.

Fuel oil: When fuel oil is burned, the Permittee is required to keep on record the purchase specification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SOx emissions using the information from above according to the following equation for any change in the conditions above:

SO2 (lb/MMBtu) = 2.0 x [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

NOx: Although there is no applicable standard for nitrogen oxides, the permittee is required to monitor the dates and hours of operation of the engines for the purposes of testing. According to the Arizona Testing Manual, a major point of emissions is required to be tested every year. However, the source has been required to be tested only once during the term of the permit according to the schedule given below. The turbines have been determined to cross the major threshold (100 tons) according to the following schedule:

1. Turbines (Nos. 1 and 2): When operated individually for 1480 hours on a twelve month rolling total basis; and
2. Turbine No. 3: When operated individually for 500 hours on a twelve month rolling total basis.
3. Turbine No. 4: When operated individually for 310 hours on a twelve month rolling total basis.
4. Turbine No. 21: When operated individually for 930 hours on a twelve month rolling total basis.

The hours were derived assuming respective primary fuel is burned in the units. The tests will be conducted when burning the primary fuel. The permit requires the permittee to report the dates and hours of operation of the turbines semi-annually, during the six months prior to the date of report. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

C. Auxiliary Boiler 1 and Plant Water Heaters

Opacity: The boiler and the water heaters are subject to the opacity standard of < 15% in A.A.C. R18-2-724.J. The boiler burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6. The water heaters burn natural gas.

Natural gas: Natural gas is a clean burning fuel and usually does not pose a visible emissions problem. Hence, no monitoring is required when burning natural gas.

Fuel oil: However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

1. When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

2. When fuel oil is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

The permittee is required to record the dates and hours of operation of the auxiliary boiler and the number of hours fuel oil is burned continuously in the boiler.

PM: The unit is also subject to the particulate matter emissions standard in A.A.C. R18-2-724.C.1.

Natural gas: Natural gas is a clean burning fuel and results in negligible particulate matter emissions as demonstrated by engineering calculations and tabulated under the PTE column in Table 4. Therefore, it was determined that a verification though engineering calculation would fulfill the requirements for periodic monitoring when burning natural gas.

Fuel oil: However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit. The permittee is also required to monitor the following information about the fuel found in the the purchase specification:

1. Heating value;
2. Ash content;

Ash content is not an accurate measure but is a good indicator of particulate matter emissions, and monitoring this would help the agency to "ballpark" the particulate matter emissions. No engineering estimation using ash content is prescribed in the permit since it could be interpreted to incorrectly correlate particulate matter emissions to ash content only. Permittee is required to keep on record a copy of the contractual agreement. Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit. It can be seen that the PTE is only 17% of the allowable emissions.

SOx: The boiler is subject to sulfur dioxide standard under A.A.C. R18-2-724.E. This standard applies only when the unit burns oil. When fuel oil is burned, the Permittee is required to keep on record the purchase specification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SOx emissions using the information from above according to the following equation for any change in the conditions above:

SO2 (lb/MMBtu) = 2.0 x [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Table 4 compares the PTE, allowable emissions, test data, and actual emissions for this unit.

NOx: There is no applicable standard and hence no monitoring is required. Also, the unit does not have the potential to be a major emission unit i.e., it cannot emit more than 100 tpy of NOx. Hence, no testing is required.

D. Cooling Tower

Opacity: The cooling tower is subject to the opacity standard of < 40% under the general visible emissions rule under A.A.C. R18-2-702.B.

PM: The unit is also subject to particulate matter emissions standard under A.A.C. R18-2-730.A.1.b. The particulate matter emissions from the cooling tower is negligible compared to the potential to emit. The potential emissions of particulate matter from the cooling tower is calculated as follows:

PM (lb/yr) = Circulation flow rate (gal/min) x density (lb/gal) x 60 (min/hr) x 24 (hr/day) x drift loss x total dissolved solids x

365 (days/year)/(1,000,000 x 100)

From application, TDS = 5000 ppm; drift loss = 0.005%; density = 8.4 lb/gal; and circulation flow rate = 40000 gpm.

PM = 22 tpy.

The allowable emission given by A.A.C. R18-2-730.A.1 (where P = 40000 x 8.4 x 60/2000 = 10,080 tons/hr) is 489 tpy. The PTE is only 4% of the allowable emissions and hence there is no need for monitoring requirements in the permit. Also, as physical constraints make particulate matter testing infeasible, ADEQ is not requiring performance tests on the cooling tower.

E. Non-point sources

The standards in Article 6 are applicable requirements for non-point sources. The following sources will be monitored:

1. Driveways, parking areas, vacant lots
2. Unused open areas
3. Open areas (Used, altered, repaired, etc.)
4. Construction of roadways
5. Material transportation
6. Material handling
7. Storage piles
8. Stacking and reclaiming machinery at storage piles

All of these areas must comply with the opacity limitation of 40%. The control measures for controlling particulate matter emissions from these sources are listed in APS's Class I permit. APS has indicated in the application, that rare instances of open burning may occur. The condition in the permit directs APS to obtain a permit from ADEQ, or the local officer in charge of issuing burn permits.

Monitoring and recordkeeping requirements for these non-point sources include a record of the date and type of activity performed and the type of controls used. Also, monitoring requirements for the applicable open burning rule may be satisfied by keeping all open burn permits on file.

F. Other Periodic Activities

Abrasive Sand Blasting

APS has indicated in the permit application that there might be a few occasions on which abrasive sand blasting activities are conducted on-site. R18-2-726 and R18-2-702 (B) are applicable requirements, and as such have to be included in the permit. It was decided to prescribe minimal monitoring requirements.

Spray Painting

APS has indicated in the permit application that there might be a few occasions on which spray painting activities are conducted on-site. R18-2-727 and R18-2-702(B) are applicable requirements, and as such, have to be included in the permit. R18-2-727(A) and R18-2-727(B) are included in the approved State Implementation Plan (SIP). R18-2-727(C) and R18-2-727(D) are also a part of the approved SIP. They are present in the definitions section of the SIP as R9-3-101.117. EPA approved SIP provision R9-3-527.C is not present in the amended rule. However, R9-3-527.C is an applicable requirement, and is federally enforceable till the current State SIP is approved by the EPA. It was decided to prescribe minimal monitoring requirements.

Mobile Sources

The Permittee has been required to keep a record of all emissions related maintenance activities performed on Permittee's mobile sources stationed at the facility as per manufacturer's specifications for the purposes of monitoring and recordkeeping.

Asbestos Demolition/Renovation

The Permittee has been required to keep a record of all required paperwork on file for the purposes of monitoring and recordkeeping. The required paperwork includes "NESHAP Notification for Renovation and Demolition Activities" form and all supporting documents.

Nonvehicle Air Conditioner Maintenance and/or Services

The Permittee has been required to keep a record of all paperwork required by the applicable requirements of 40 CFR 82 - Subpart F on file for the purposes of monitoring and recordkeeping.

VIII. TESTING REQUIREMENTS

Gas Turbines

The permittee is required to test each unit for conventional air pollutants that are emitted in quantities above 100 tons in a year based on the schedule given in Section VII.B of this document. The reasons for this test are as follows:

1. the test will have a direct impact on the annual emission fee;
2. the test will be the basis for any future modification; and
3. the test will help to get a clearer picture of the actual emissions from major sources in

Arizona. While emission factors play an important role in the air pollution control program, they do not yield reliable data unless they are either developed directly from the emission unit in question or substitutes for a proven mass-balance relationship. Thus, testing would provide valuable information.

IX. INSIGNIFICANT ACTIVITIES

The following activities were listed as insignificant by the Permittee in their application and have been deemed either insignificant or not insignificant by the Department here:

S. No.	Activity	Determination	Comments
1.	Accidental fires.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
2.	Acetylene, butane, and propane torches.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
3.	Acid tank vents.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
4.	Activities associated with maintenance, repair, or dismantlement of an emission unit or other equipment.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
5.	Administration building gas heaters.	No	Subject to A.A.C. R18-2-724
6.	Aerosol can usage.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
7.	Auxiliary boiler blowdown.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
8.	Auxiliary boiler safety relief valves	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
9.	Bearing cooling water.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
10.	Boiler acid wash.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
11.	Boiler feed pump hydraulic coating.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

S. No.	Activity	Determination	Comments
12.	Brazing and soldering activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
13.	Cathodic protection.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
14.	Caulking operations.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
15.	Caustic tank vents.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
16.	Chemical storage tanks (limited to chemicals not listed in 40 CFR 68.13, chemicals listed in 40 CFR 68.13 but stored in quantities less than threshold levels, and not subject to any applicable regulation under the Act or the Arizona Revised Rules)	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
17.	Chemical storage, hazardous products, and staging area (limited to chemicals not listed in 40 CFR 68.13, chemicals listed in 40 CFR 68.13 but stored in quantities less than threshold levels, and not subject to any applicable regulation under the Act or the Arizona Revised Rules).	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
18.	Cooling tower chemical additives (limited to chemicals not listed in 40 CFR 68.13, chemicals listed in 40 CFR 68.13 but stored in quantities less than threshold levels, and not subject to any applicable regulation under the Act or the Arizona Revised Rules).	No	Insignificant pursuant to A.A.C. R18-2-101.54.j
19.	Corona.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
20.	Demineralizer regeneration.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
21.	Electric motors.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
22.	Emissions sampling and associated activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
23.	Evaporation pond.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
24.	Evaporative coolers.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

S. No.	Activity	Determination	Comments
25.	Facilities used for preparing food.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
26.	Fire fighting activities and training.	No	Subject to A.A.C. R18-2-602
27.	Flammable storage cabinets.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
28.	Flares used to indicate danger to the public.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
29.	Fuel oil piping systems including: flanges, valves, pump seals, pressure relief valves, and other individual components.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
30.	Fugitive dust emissions from the operation of passenger vehicles.	No	Subject to A.A.C. R18-2-604
31.	Gas turbine false start drains.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
32.	Gas turbine gas vent #1.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
33.	Gas turbine gas vent #2.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
34.	Gas turbine gas vent #3.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
35.	Gas turbine lube oil vents.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
36.	Gas turbine starting diesel engines.	No	Subject to A.A.C. R18-2-719
37.	Gas yard vents.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
38.	General offices activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
39.	Hot water heater.	No	Subject to A.A.C. R18-2-724

S. No.	Activity	Determination	Comments
40.	Hydraulic system reservoirs.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
41.	Individual steam unit ignitors and fuel burner assemblies.	No	Subject to the applicable standards of the steam unit
42.	Individual steam unit soot blowers.	No	Subject to the applicable standards of the steam unit
43.	Janitorial activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.a
44.	Laboratory facilities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.i
45.	Landscaping equipment.	No	Subject to A.A.C. R18-2-801
46.	Lube oil storage area.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
47.	Maintenance shop heaters.	No	Subject to A.A.C. R18-2-724
48.	Medical activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
49.	Mercury exhaust hood.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j. See letter dated July 6, 1998.
50.	Natural gas fuel piping system including: flanges, valves, pump seals, pressure relief valves, and other individual components.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
51.	Normal usage of miscellaneous consumer products.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
52.	Oil circuit breakers.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
53.	Oil filter draining.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

S. No.	Activity	Determination	Comments
54.	Paint storage area.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
55.	Painting.	No	Subject to A.A.C. R18-2-727
56.	Pesticide/herbicide activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
57.	Portable testing equipment and testing activities.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
58.	Portable welder.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
59.	Production of hot water not related to industrial process.	No	Subject to A.A.C. R18-2-724
60.	Pump/motor oil reservoirs.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
61.	PVC/ABS pipe welding.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
62.	Repair and maintenance of roads or other paved or open areas.	No	Subject to A.A.C. R18-2-604
63.	Safety devices, fire extinguishers, and cardox systems.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
64.	Sandblasting.	No	Subject to A.A.C. R18-2-726
65.	Satellite accumulation barrels.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
66.	Septic tanks.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
67.	Service water tank and piping.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
68.	Small equipment fueling area.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

S. No.	Activity	Determination	Comments
69.	Smoking areas.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
70.	Solvent cleaning tank.	No	Subject to A.A.C. R18-2-730
71.	Station transformers.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
72.	Steam cleaners.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
73.	Steam unit air ejector.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
74.	Steam unit and gas turbine battery banks.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
75.	Steam unit boiler blowdown.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
76.	Steam unit drum vents.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
77.	Steam unit gas vent.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
78.	Steam unit gland steam exhauster.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
79.	Steam unit hydrogen scavenging and vents.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
80.	Steam unit oil tank vents	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
81.	Steam unit safety relief valves.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
82.	Storage tank #1, 100,000 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
83.	Storage tank #2, 30,000 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

S. No.	Activity	Determinatio n	Comments
84.	Storage tank #3, 6000 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
85.	Storage tank #4, 60,000 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
86.	Storage tank #5, 100,000 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
87.	Storage tank #6, 50,000 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
88.	Storage tank #7, 286 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.c
89.	Storage tank #7, 13.7 bbls, Fuel oil.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.c
90.	Storm water drainage area.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
91.	Used oil storage area.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j
92.	Welding.	Yes	Insignificant pursuant to A.A.C. R18-2-101.54.j

X. ADDITIONAL INFORMATION REQUESTED (if applicable)

The Permittee submitted the Title V application on February 1, 1995. The application was deemed complete on April 1, 1995. Revised estimates of SO2 emissions were submitted by the source in March 1995. The source was asked to quantify emissions from the storage tanks at the site in November 1995. Source responded to this request for additional information in January 1996. No other requests were made after this date.